EFFECT OF OPERATING PARAMETERS OF HYDRAULIC FRACTURING TECHNOLOGY AND RESERVOIR POROSITY ON FRACTURE GEOMETRY

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ABSTRACT: In the past decades, a large amount of oil production in the Cuu Long Basin was mainly exploited from the basement reservoir and one part from oil production in the Miocene sandstone reservoir, and a small amount of oil production from the sandstone Oligocene reservoir. Many discovery wells and production wells in lower Oligocene sandstone had high potential of oil and gas production reserves in which the average reservoir porosity was from 10% to 18%, and reservoir permeability was in the range of 0.1 md to 5 md. Due to high reservoir heterogeneity, complicated geological structure in high closure pressure up to 7,700 psi, the problem in the Oligocene reservoir is very poor fracture conductivity among the fractures with the upper seal and lower seal by shale. The big challenging deal with this problem is to stimulate the reservoir by hydraulic fracturing to enhance oil and gas production which is required to the study. In this article, the author has presented the effects of operating parameters of hydraulic fracturing as injection time, injection rate, leak-off coefficient, and reservoir porosity based on the 2D PKN-C fracture geometry accounting for leak-off coefficient, spurt loss in terms of power law parameters on economic performance by design of experiment (DOE) and apply a tool of response surface method with the recommended ranges of operating parameter in the field experience. In the recent years, through the successful application of hydraulic fracturing to stimulate reservoirs for well completion in Oligocene reservoir, that technique has widely been used in the field for improving oil production.

Key words: Operating parameters of hydraulic fracturing, the 2D PKN-C fracture geometry, economic performance, operating parameters, reservoir parameter.

OLIGOCENE RESERVOIR DESCRIPTION

The energy demand of oil and gas is rapidly increased worldwide and the energy supply for developing the domestic economy is necessary particularly. Therefore, to increase oil production rate by tertiary method, the hydraulic fracturing stimulation is widely used in the petroleum industry for enhancing oil production to apply the vertical well, multistage hydraulic fracturing in horizontal well. In Vietnam, oil production rate in the Oligocene reservoir was declined in a long time due to many reasons such as the decline in pressure of reservoir, the low reservoir permeability from 0.1 md to 5 md, and low reservoir porosity from 10 % to 18 %, heterogeneity, and complexity of the reservoir. These problems lead to poor conductivity among the fractures. To deal with this problem, it is necessary to stimulate the reservoir of hydraulic fracturing stimulation. In the Cuu Long basin, there are three pay zones of oil production that consist of the basement reservoir, Miocene sandstone

reservoir, and the Oligocene sandstone reservoir. In the previous report, the amount of oil production reserves which can be exploited from the basin has been estimated at about 5,600 million to 5,950 million barrels of oil equivalent. That is equal to potential hydrocarbon reserves of about 22.4 billion to 23.8 billion of oil equivalents. In which, 70% of oil production is exploited in the fracture basement reservoir, whereas 18% of oil production in the Oligocene reservoir (1,033 million barrels of oil reserves) and 12% of oil production in the Miocene reservoir, respectively. On the other hand, total amount of oil production in Oligocene reservoir in the White Tiger oil field is only 76.7 million barrels of oil which is equal to 4.6% of total amount of oil production in the White Tiger and 7.4% of oil in the Oligocene reservoir. These layers in the Oligocene reservoir include Tra Tan of Oligocene C, Oligocene D and Oligocene E, Tra Cu in the Oligocene F. In this article, the author has mentioned in the Oligocene E reservoir and has presented the effects of operating parameters of hydraulic fracturing and reservoir porosity on economic performance in the Oligocene reservoir. The result of the research is very useful in order to select good operating parameters of hydraulic fracturing in the Oligocene. In the future work, the author will present the combined operating parameters of hydraulic fracturing and the other parameters that cannot be controlled such as reservoir permeability, fracture height, reservoir porosity effect on the economic performance.

FRACTURING FLUID SELECTION AND FLUID MODEL

In 1991, Economides et al., presented fracturing fluid selection guide for petroleum industry practices. Ideally, the fracturing fluid is compatible with the formation rock properties; also it is compatible with fluid flow in the reservoir, reservoir pressure and reservoir temperature. Fracturing fluid that generates pressure in order to transport proppant slurry and open fracture, produce fracture growth during pumping, also fracturing fluid should minimize pressure drop alongside and inside

the pipe system in order to increase pump horsepower with the aim of increasing a net fracture pressure to produce more fracture propagation. In fracturing fluid system, the breaker additive would be added to the fluid system to clean up the fractures after treatment. Due to high temperature of Oligocene E reservoir up to $266^{o}F$, Borate- crosslinked 30 pptg HPG with persulfate with 8 pptg $Na_2S_2O_8$ has been selected for fracturing fluid system. To predict precisely the fracture geometry as fracture half-length, fracture width during pumping, the power law fluid model would be applied in this study. Then the most fracturing fluid model is usually given by:

$$\tau = K\gamma^{n} \qquad (1)$$

Where: τ- shear stress, γ- shear rate, K- consistency coefficient, n- rheological index as flow behavior index that is non-dimensional but related to the viscosity of the non-Newtonian fracturing fluid model [1].

The power law model can be expressed by:

$$\log \tau = \log K + \text{n} \log \gamma$$

$$\text{Slope} = [(N\sum XY) - (\sum X \sum Y)]/[(N\sum X^2) - (\sum X)^2]$$

$$\text{Intercept} = (\sum Y - n \sum X)/N$$

Where $X = \log \gamma$, $Y = \log \tau$, and $N = $ Data number. Thus $n = $ Slope and $K= $ Exp(Intercept).

PROPPANT SELECTION

In order to select proppant, the proppant would be selected correctly as proppant type, proppant size, proppant porosity, proppant permeability and proppant conductivity, strength proppant under effective stress pressure of the reservoir. In order to evaluate precisely the fracture conductivity of the fractures account for proppant damage factor, of course proppant is used to open fractures and keep the fractures open for a long time in high fracture conductivity while pump pressure is shut down and fracture begins to close due to effective stress and overburden pressure. Ideally, proppant selection needs to be enough proppant strength to resist the crush, erosion, and corrosion in the well. Due to closure pressure of Oligocene reservoir up to 7,700 psi,

proppant type that should be selected is the intermediate strength proppant (ISP) as Carbo Lite Ceramics proppant with proppant size of 20/40, (Nolte and Economides) which is good at fracturing fluid as presented in the fluid selection.

Table 1. Proppant selection at optimal parameters

Parameter	Value
Proppant type	20/40 CARBO-Lite
Specific gravity	2.71
Strength	Intermediate
Diameter	0.0287 in
Packed porosity	0.35
Conductivity at 7,700 psi closure pressure (at 1.78 lb/ft^2)	3,400 md-ft.
Conductivity damage factor	0.6
Closure pressure	7,700 psi

FRACTURE GEOMETRY MODEL

In this study, the 2D PKN fracture geometry model (Two dimension PKN; Perkins and Kern, 1961; Nordgren, 1972) in fig. 1 is used to present the significant fracture geometry of hydraulic fracturing stimulation for low permeability, low porosity and poor conductivity as Oligocene E reservoir, which requires the fracture half-length of fracture design and evaluates the fracture geometry. After incorporation of carter solution II, the model known as 2D PKN-C (Howard and Fast, 1957) has incorporated the leak-off coefficient, in terms of consistency index (K), flow behavior index (n), injection rate, injection time, fluid viscosity, fracture height. The model detail in (Valko's and Economides, 1995) is shown in table 2 [2].
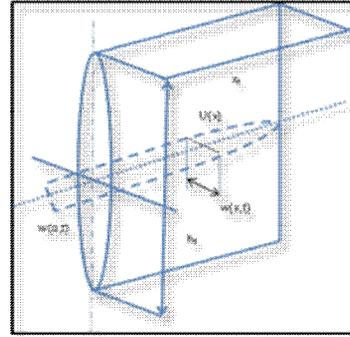

Fig. 1. The 2D PKN-C fracture geometry model

Table 2. Reservoir data of X well in Oligocene E reservoir, offshore Vietnam

Parameter	Value
Target fracturing depth, ft.	12,286
Reservoir drainage area, acres	122
Reservoir drainage radius, ft.	1,300
Wellbore radius, ft.	0.328
Reservoir height, ft.	72
Reservoir porosity, %	10% to 18%
Reservoir permeability, md	0.5
Reservoir fluid viscosity, cp	1.5
Oil formation volume factor, RB/STB	1.4
Total compressibility, psi^{-1}	1.00×10^{-5}
Young's modulus, psi	5×10^6
Sandstone Poisson's ratio	0.25
Initial reservoir pressure, psi	4,990
Reservoir temperature, $^{\circ}$F	266
Oil API	36.7
Gas specific gravity	0.79
Bubble point pressure, psi	1,310
Flowing bottom hole pressure, psi	3,500
Closure pressure, psi	7,700

The maximum fracture width in terms of the power law fluid parameters is given by:

$$w_f = 9.15^{\frac{1}{2n+2}} \times 3.98^{\frac{n}{2n+2}} \left(\frac{1+(\pi-1)n}{n} \right)^{\frac{n}{2n+2}} K^{\frac{1}{2n+2}} \times \left(\frac{(q_i/2)^n h_f^{1-n} x_f}{E'} \right) \tag{2}$$

Where: E' is the plain strain in psi, ($E' = \dfrac{1}{1-v^2}$).

Where: n is flow behavior index (Dimensionless); K is the consistency index (Pa.sec^n); v is in the Poisson's ratio and μ is in Pa.s (M. M. Rahman, (2002)), the power law parameters are correlated with fluid viscosity of fracturing fluid as:

$$n = 0.1756 \times (\mu)^{-0.1233}$$

$$K = 47.880 \times (0.5\mu - 0.0159)$$

By using the shape factor of π/5 for a 2D PKN fracture geometry model, the average fracture width (w_a) is given by π/5 × w_f as equation.

$$w_a = \frac{\pi}{5} \times 9.15^{\frac{1}{2n+2}} \times 3.98^{\frac{n}{2n+2}} \left(\frac{1+(\pi-1)n}{n} \right)^{\frac{n}{2n+2}} K^{\frac{1}{2n+2}} \times \left(\frac{(q_i/2)^n h_f^{1-n} x_f}{E'} \right) \qquad (3)$$

Carter II solution formulates material balance in terms of injection rate to the well. At the injection time t_e, the injection rate enters one wing of the fracture area, the material balance presents the relationship between injection rate (q) which is the total fracture volume with fluid volume losses to fractures. The material balance is presented as equation below.

$$q = 2\int_0^t \frac{C_L}{\sqrt{t-\tau}} \times \left(\frac{dA}{d\tau} \right) d\tau + 2S_p \times \frac{dA}{dt} + w \times \frac{dA}{dt} + A\frac{dw}{d\tau} \qquad (4)$$

With an analytical solution for constant injection rate (q), Carter solved the material balance that gives the fracture area for two wings as:

$$A(t) = \frac{w_a + 2S_p}{4C_L^2 \pi} \times q \left[exp(\beta^2)erfc(\beta) + \frac{2\beta}{\sqrt{\pi}} - 1 \right] \qquad (5)$$

Hence fracture half-length with the fracture surface area ($A(t) = 2\,x_f h_f$) is given by.

$$A(t) = \frac{(w_a + 2S_p)}{4\pi C_L^2 h_f} \times \frac{q}{2} \left[exp(\beta^2)erfc(\beta) + \frac{2\beta}{\sqrt{\pi}} - 1 \right] \qquad (6)$$

Where is $\beta = \dfrac{2C_L\sqrt{\pi t}}{w_a + 2S_p}$

Equation (6) presents the fracture half-length during proppant slurry injection into the fractures and also describes the fracture propagation alongside the fractures with time, in which fracture half-length depends on several parameters as injection rate (q), injection time (t), leak-off coefficient (C_L), spurt loss (S_p), and fracture height (h_f), the average fracture width (w_a). From the close of equation (6) it can be easy to determine the valuable fracture half-length by using iterative method calculation. The PKN-C fracture geometry model can be seen the figure 1.

MATERIAL BALANCE

Carter solved the material balance to account for leak-off coefficient, spurt loss, injection rate, injection time, and in terms of power law parameters as flow behavior index of n and consistency index of K. Proppant slurry is pumped to the well under high pressure to produce fracture growth and fracture propagation. Therefore, the material balance is expressed as equation: $V_i = V_f + V_l$, where V_i is the total fluid volume injected to the well, V_f is the fracture volume that is required to stimulate reservoir, and V_l is the total fluid volume losses to the fracture area in the reservoir. The fracture volume, V_f, is defined as two sides of the symmetric fracture of $V_f = 2x_f h_f w_a$, the fluid efficiency is defined by V_f/V_i. In 1986, Nolte proposed the relationship between the fluid volumes injected to the well with pad volume and also proposed a model for proppant schedule. At the injection time t, the injection rate is entered into two

wings of the fractures with q, the material balance presented as the constant injection rate q is the sum of the different leak-off flow rate and fracture volume as:

$$q = 2\int_0^t \frac{C_L}{\sqrt{t-\tau}} \times \left(\frac{dA}{d\tau}\right) d\tau + 2S_p \times \frac{dA}{dt} + w \times \frac{dA}{dt} + A\frac{dw}{d\tau} \tag{7}$$

The fluid efficiency of fractured well of the post fracture at the time (t) is given by:

$$\eta = \frac{w_a h_f x_f}{qt} \ or \ \eta = \frac{w_a h_f\left(w_a + 2S_p\right)}{4\pi C_L^2 t} \times \left[exp\left(\beta^2\right)erfc\left(\beta\right) + \frac{2\beta}{\sqrt{\pi}} - 1 \right] \tag{8}$$

Where, $\beta = \dfrac{2C_L\sqrt{\pi t}}{w_a + 2S_p}$ and C_L is the leak-off coefficient in ft/min$^{0.5}$, w_a is the average fracture width in the fractures in inch, S_p is the spurt loss in the fractures in gal/ft^2.

CENTRAL COMPOSITE DESIGN (CCD)

The design of experiment (DOE) techniques is commonly used for process analysis and the models are usually the full factorial, partial factorial, and central composite rotatable designs. An effective alternative to the factorial design is the central composite design (CCD), which was originally developed by Box and Wilson and improved by Box and Hunter in 1957. The CCD was widely used as a three-level factorial design, requires much fewer tests than the full factorial design, and has been provided to be sufficient as describing the majority of steady state products of response. Currently, CCD is one of the most popular classes of design used for fitting second-order models. The total number of tests required for is $2^k + 2k + n_o$, including the standard 2^k factorial points with its origin at the center, $2k$ points fixed axially at a distance, say β ($\beta = 2^{k/4}$), from the center to generate the quadratic terms, and replicate tests at the center (n_o), where k is the number of independent variables. These operating parameters of the variables are namely of injection rate of X_1, injection time of X_2, leak-off coefficient of X_3, and reservoir porosity of X_4, presenting the total number of tests that were required of the four variables of $2^4 + (2.4) + 3 = 27$ runs. In this experimental design, the center points were set at 3 and the replicates of zero value. Therefore, the three independent variables of the operating parameters of the CCD were shown in table 2. The coded and actual levels of the dependent variables of each the experiment design in the matrix column is calculated in table 3. From table 3, the experiment of design is conducted for the obtaining the response.

Table 3. Four independent variables and their levels for Central Composite Design (CCD)

Variables	Symbol	Coded variable level		
		Low	Center	High
Variables	Symbol	-1	0	1
Injection rate, bpm	X_1	18	19	20
Injection time, minutes	X_2	60	90	120
Leak-off coefficient, ft/min$^{0.5}$	X_3	0.003	0.005	0.007
Reservoir porosity, %	X_4	10	14	18

THE RECOMMENDION ON THE RANGES OF THE OPERATING PARAMETERS OF HYDRAULIC FRACTURING AND RESERVOIR POROSITY OF OLIGOCENE RESERVOIR

Table 4. Fracturing parameters

Parameter	Value
Fracture height, h_f, ft.	72
Sandstone Poisson's ratio	0.25
Leak-off coefficient, $ft/min^{0.5}$	0.003 to 0.007
Young's modulus, psi	5.00×10^6
Injection rate, bpm	18 to 22
Injection time, min	60 to 120
Spurt loss, in	0
End of job (EOJ) proppant concentration, ppg	8
Flow behavior index, n	0.55
Consistency index, K, $lbf.s^n/ft^2$	0.04
Fracturing fluid type: Cross-linked of 30 pptg HPG Persulfate with 8 pptg breaker $Na_2S_2O_8$	

Interestingly, the hydraulic fracturing treatment in the field can be divided into two types of parameters as operating parameters of hydraulic fracturing such as injection rate, injection time, and leak-off coefficient at which these parameters are controlled from the surface and facilities and the rest of parameters cannot be controlled such as rock properties, young modulus, poisson's ratio, geological structural, reservoir porosity, reservoir permeability, fracture closure pressure and the stress regime of the fracture of normal fault stress regime, strike slip regime, reverse faulting stress regime. In this article, the author has presented the effect of operating parameters of hydraulic fracturing and reservoir porosity on economic performance. Accordingly, the normal faulting stress regime of the reservoir with the minimum horizontal stress as closure pressure is up to 7,700 psi. In this research, the recommended operating parameter is based on the field experience offshore Vietnam. The injection rate is in the range from 18 bpm to 22 bpm, injection time i in the range of 60 minutes to 120 minutes, and the leak-off coefficient i in the range of 0.003 $ft/min^{0.5}$ to 0.007 $ft/min^{0.5}$ for designing the leak-off coefficient in Oligocene sandstone reservoir, and the reservoir porosity ranges from 10% to 18%. One of the important operating parameters of hydraulic fracturing is the leak-off coefficient at which the leak-off coefficient had more effect on the fracture geometry of the fracture half-length and fracture width as well as the economic performance. Currently total leak-off coefficient is controlled by three mechanisms of rock compressibility, invaded zone, and wall building effect. In the three mechanisms, only one parameter can controll filtration viscosity of fracturing fluid system. Usually the increasing fracturing fluid viscosity as high polymer concentration of fracturing fluid leads to high fracturing fluid density. It can decrease the wall building effect as decrease in the total leak-off coefficient. In this research, the author proposed the fracturing fluid parameters and fluid properties as in table 4.

The model for overall leak-off coefficient was presented by Williams, (1970) and Williams et al., (1979) [3, 4] as:

$$C_1 = \frac{-\dfrac{1}{C_c} + \sqrt{\dfrac{1}{C_c^2} + 4\left(\dfrac{1}{C_v^2} + \dfrac{1}{C_w^2}\right)}}{2\left(\dfrac{1}{C_v^2} + \dfrac{1}{C_w^2}\right)} \qquad (9)$$

That formula is modified as equation below:

$$\frac{2}{C_1} = \frac{1}{C_c} + \sqrt{\frac{1}{C_c^2} + 4\left(\frac{1}{C_v^2} + \frac{1}{C_w^2}\right)} \qquad (10)$$

In which, C_c is the total compressibility fluid loss leak-off in reservoir conditions in $ft/min^{0.5}$ that calculated by the equation below:

$$C_c = S_o C_o + S_w c_w + S_g C_g + C_r$$

In which, S_o is the oil saturation in %; C_o is the compressibility of oil in psi^{-1}; S_w is the water saturation in %; c_w is the compressibility of the water in psi^{-1}; S_g is the gas saturation in %; C_g is the compressibility of gas in psi^{-1}; C_r is the compressibility of the rock in psi^{-1}; C_v is the viscous fluid loss coefficient due to the filtration in $ft/min^{0.5}$; C_w is the wall building of fluid loss coefficient in $ft/min^{0.5}$; C_t is the total compressibility in psi^{-1}; C_c is leak-off coefficient due to total compressibility in $ft/min^{0.5}$; C_l is the leak-off coefficient in $ft/min^{0.5}$.

FRACTURE CONDUCTIVITY

The value of fracture conductivity that is usually measured from laboratory data (API standard) based on proppant type, proppant size, proppant shape, proppant damage factor, proppant permeability, proppant porosity under closure pressure is very important to predict the oil production. The API standard for a test such as data to measure linear flow through the proppant pack between steel plates under specific pressure is applied to it. Then the standard API is usually tested at a proppant concentration of 2 lb/ft^2. This theory most published data measured by API test (Smith, (1997)).

If the proppant permeability under closure pressure known for the each proppant type was selected, then in-situ fracture conductivity can be evaluated by.

$$Fracture\ conductivity = k_f \times w_p \qquad (11)$$

In terms of simulation fracture conductivity, if the closure pressure, proppant fracture concentration in (lb/ft^2) is known by

using Mfrac software, it can also calculate a fracture conductivity, proppant permeability, proppant porosity under closure pressure.

DIMENSIONLESS FRACTURE CONDUCTIVITY

The dimensionless fracture conductivity, F_{CD}, can be defined as (Cinco-Ley et al., (1978)) and given by:

$$F_{CD} = \frac{k_f \times w_p}{k \times x_f} \qquad (12)$$

In which: k is the reservoir permeability in mD; x_f is the fracture length of fractured well in ft.; k_f is the proppant permeability under closure pressure applied on the proppant laden; w_p is the propped fracture width at the end of the job.

Transient production flow regime

Based on the constant bottom hole pressure situation, the oil production from fractured well in transient flow regime can be calculated by (Economides et al., (1994)).

$$p_i - p_{wf} = \frac{162.6 q_o B \mu}{kh} \left(\log t + log\left(\frac{k}{\phi \mu c_t r_w^{'2}} \right) + s_f - 3.23 \right) \qquad (13)$$

In which, $r_w^{'}$ is the effective wellbore radius and given by: $r_w^{'} = r_w e_f^{-s}$, s_f is pseudo-skin is calculated by the relationship (Valko's et al., 1997): $s_f = F - ln\left(\frac{x_f}{r_w} \right)$, where x_f is the fracture half-length, and r_w is the wellbore radius. The F factor can be calculated by:

$$F = \frac{1.65 - 0.328u + 0.116u^2}{1 + 0.18u + 0.64u^2 + 0.005u^3} \qquad (14)$$

Where $u = ln(F_{CD})$ and F_{CD} is the dimensionless fracture conductivity which is calculated by $F_{CD} = \frac{k_f w_p}{kx_f}$, also F_{CD} is related to proppant number which is along the penetration ratio ($l_x = 2x_f/x_e$) and $k_f w_p$ is the fracture conductivity which can be calculated by laboratory

experiment or conductivity simulation when knowing a propant fracture concentration in lb/ft^2 inside fracture under closure pressure applied on the proppant laden. Basically, the proppant number is defined by (Economides et al., 2001).

$$N_{propp} = \left(\frac{2k_f}{k_{res}} \right) \times \frac{V_{prop}}{V_{res}} \qquad (15)$$

Where k_f is the effective proppant pack permeability; k is the reservoir permeability; V_{prop} is the propped volume in the pay zone (two wings, including void space between the proppant grains); V_{res} is the drainage volume. The transient production period is often short time oil production.

NET PRESENT VALUE (NPV) MODEL

In 1986, Veatch presented a comprehensive procedure of the various techniques. In 1987,

Meng and Brown proposed the net present value (*NPV*) as an approximate treatment optimization approach. In 1988, Balen et al., presented a series of the parametric studies and the components of the *NPV* calculation. Net present value is defined as the revenue from the production forecast for the fractured well less the production forecast for the same reservoir with unstimulated well and the total cost of treatment in current dollars. In this research, the net present value of the future revenue can be calculated by the following equation:

$$NPV = \sum_{j=1}^{N} \frac{(V_F)_j}{(1+i)^j} - \sum_{j=1}^{N} \frac{(V_o)_j}{(1+i)^j} - C_{tr} \qquad (16)$$

$$C_{tr} = C_{pr} + C_{tfl} + C_{pu} + FC \qquad (17)$$

In order to calculate total fluid cost, Rahman et al., 2003 presented to calculate total fluid volume without proppant as the following equation:

$$V_{tfl} = V_{pad} + V_{fl} \qquad (18)$$

To compute the fracturing fluid volume of proppant slurry stage, then the amount of fracturing fluid volume is only mixed with dry proppant in the slurry stage and given by:

$$V_{fl} = \frac{W_{pr}}{\overline{P_c}} \qquad (19)$$

In which, $\overline{P_c} = \eta P_c$.

Where: C_{tr} is the total treatment cost in \$; C_{pr} is the total proppant cost in \$; C_{tfl} is the total fluid cost in \$; C_{pu} is the total pumping horse power cost in \$; C_F is the total fixed cost in \$; $\overline{P_c}$ is the average proppant concentration in ppg; P_c is the end of job (EOJ) proppant concentration, finally η is the fluid efficiency; W_{pr} is the total proppant mass in lbs; V_{pad} is the pad volume in gallons; V_{fl} is the total fluid loss in gallons without proppant.

Where: *NPV* is the net present value in a fractured well; *N* is the number of periods; V_F is the fracture value production revenue of a stimulated case reservoir; V_o is the fracture value production revenue of an unstimulated case reservoir; *i* is the discount rate in %.

OLIGOCENE RESERVOIR DATA

The well was drilled with appraisal oil well production reserves in the Pre-Tertiary fractured basement reservoir and the Oligocene sandstone reservoir of the field in Cuu Long basin, offshore Vietnam. In this study, the reservoir data is gathered from the Lower Oligocene reservoir with the reservoir depth of 3,400 m to 4,000 m and the reservoir data presented in table 4.

DESIGN OF EXPERIMENT USING CENTRAL COMPOSITE DESIGN FOR OPERATING PARAMETERS OF HYDRAULIC FRACTURING AND ECONOMIC MODEL

The injection rate of hydraulic fracturing for Oligocene reservoir follows the field experience at which the injection rate was considered in the range from 18 bpm to 22 bpm of the variable X_1 (Rahman, M. M., (2008)). Usually, the injection rate has more effect on the fracture half-length as the injection rate is increased, the fracture half-length is increased, the fracture conductivity and the net present value (NPV) are also increased. Accordingly, when the injection rate decreases, the fracture half-length decreases, the fracture conductivity and the net present value of course decrease (Haiqing Yu and Rahman, M. M., SPE 152439). Similarly, the effect of injection time on the fracture half-length was presented by Haiqing Yu and Rahman, M. M., SPE 152439. The research presented that the increase in the injection time leads to the increase in fracture half-length. Whereas, the decrease in the injection time leads to decrease in the fracture half-length because the injection time is directly proportional to fracture half-length (Economides et al.,). Thus, the injection time is a very important variable which has much affect on the fracture half-length as well as the net present value (*NPV*). Many studies previously confirmed that injection time is directly proportional to net present value with the limited injection time following the range of field experience. Oftentimes, the injection

time of hydraulic fracturing stimulation for tight oil reservoir is considered as 60 minutes to 120 minutes of the variable X_2 (Rahman, M. M., (2008)). The effect of the leak-off coefficient on the net present value was presented by (Economides et al., (1993)); the presentation performed that the total leak-off coefficient increases, the net present value decreases because the more leak-off coefficient usually leads to more fluid volume loss and narrow fracture dimension as poor fracture conductivity of the post fracture. Thus, the high leak-off coefficient as low polymer concentration of the hydraulic fracturing reduces oil production rate in the post fracture. Whereas, the low leak-off coefficient of high polymer concentration of fracturing fluid leads to more fracture dimensions during fracturing of longer fracture length and wider fracture

width as more fracture conductivity. Thus, low leak-off coefficient increases the net present value. Usually, the total leak-off coefficient is directly proportional to the main polymer concentration and fluid additive. In this study, hydraulic fracturing for the field of tight oil reservoir with the leak-off coefficient is considered in the range of 0.002 ft/min$^{0.5}$ to 0.004 ft/min$^{0.5}$ of the variable X_3 as shown in the table 2. And the porosity is the important parameter in order to evaluate the oil production rate of the reservoir at that time. Furthermore, oil production rate is gradually declined in 10 years because the reservoir porosity is gradually reduced from 18% to 10%. Therefore, the cumulative oil production has been reduced due to the reduce in reservoir porosity.

Table 5. Independent variables and results from post-production with simulation observed by Central Composite Design (CCD)

	Coded level of the variables				Actual level of variables				Response (Simulation and observed)		
Run	X_1	X_2	X_3	X_4	Injection rate, bpm	Injection time, min	Leak-off, ft/min$^{0.5}$	Por, %	Fracture half-length, ft	Cumulative production, Mbbls	NPV, $mm
1	-1	-1	-1	-1	18	60	0.003	10	499.8	459.531	11.9
2	1	-1	-1	-1	22	60	0.003	10	602.7	465.741	12.2
3	-1	1	-1	-1	18	120	0.003	10	727.2	469.65	12.2
4	1	1	-1	-1	22	120	0.003	10	879.0	473.96	12.3
5	-1	-1	1	-1	18	60	0.007	10	235.3	428.942	10.7
6	1	-1	1	-1	22	60	0.007	10	286.2	439.364	11.1
7	-1	1	1	-1	18	120	0.007	10	336.1	445.069	11.3
8	1	1	1	-1	22	120	0.007	10	409.2	453.612	11.6
9	-1	-1	-1	1	18	60	0.003	18	499.8	508.662	13.9
10	1	-1	-1	1	22	60	0.003	18	602.7	516.194	14.2
11	-1	1	-1	1	18	120	0.003	18	727.2	520.938	14.3
12	1	1	-1	1	22	120	0.003	18	879.0	526.175	14.5
13	-1	-1	1	1	18	60	0.007	18	235.2	471.731	12.5
14	1	-1	1	1	22	60	0.007	18	286.1	484.28	12.9
15	-1	1	1	1	18	120	0.007	18	336.1	491.165	13.1
16	1	1	1	1	22	120	0.007	18	409.2	501.494	13.5
17	-1	0	0	0	18	90	0.005	14	396.6	477.616	12.6
18	1	0	0	0	22	90	0.005	14	481.5	486.021	12.9
19	0	-1	0	0	20	60	0.005	14	355.0	473.531	12.5
20	0	1	0	0	20	120	0.005	14	510.3	487.58	13
21	0	0	-1	0	20	90	0.003	14	687.8	496.726	13.4
22	0	0	1	0	20	90	0.007	14	321.5	468.992	12.3
23	0	0	0	-1	20	90	0.005	10	439.1	455.663	11.7
24	0	0	0	1	20	90	0.005	18	439.1	503.97	13.7
25	0	0	0	0	20	90	0.005	14	439.1	482.183	12.8
26	0	0	0	0	20	90	0.005	14	439.1	482.183	12.8
27	0	0	0	0	20	90	0.005	14	439.1	482.183	12.8

The reasonable experiment design of the central composite design is to investigate the effects of three operating parameters of hydraulic fracturing and one parameter from the reservoir porosity on the production performance to the net present value of the response. These operating parameters of the variables, namely injection rate, X_1, injection time, X_2, leak-off coefficient, X_3, and reservoir porosity, X_4, have presented the total number of test that was required of the four variables of

$2^4 + (2.4) + 4 = 27$. In this experiment design, the center point was set of 3 and the replicates of zero value. Therefore, the three independent variables of the operating parameters of the CCD were shown in table 5. The coded and actual levels of the dependent variables of each the experiment design in the matrix column is calculated in table 6. From table 6, the experiment of design is conducted for obtaining the response.

Table 6. ANOVA analysis

NPV	DF	SS	MS	F	P	SD
Total	27	4.37401×10^{15}	1.62×10^{14}			
Constant	1	4.34975×10^{15}	4.34975×10^{15}			
Total connected	26	2.42588×10^{13}	9.3303×10^{11}			965935
Regression	14	2.42476×10^{13}	1.73197×10^{12}	1865.35	0.000	1.31604×10^6
Residual	12	1.11419×10^{10}	9.28496×10^8			30471.2
Lack-off fit	10	1.11419×10^{10}	1.11419×10^9	1.386×10^{11}		33379.6
Pure error	2	0.0160732	0.00803661			0.0896472
N=27 DF=12	$Q^2 = 0.997$ $R^2 = 0.99$ $R^2_{Adj.} = 0.98$		Cond.no.=6.6122 Y-miss =0 RSD=30471.228			

The net present value model for 10 years of oil production of each run with the average reservoir pressure is of 4,990 psi and bottom hole flowing pressure is set at 3,500 psi. Table 3 summarized the result of the response in order to analyze the fractured well of the post fracture production. Therefore, the independent variables are correlated with the surface response. From the response of the net present value and the result of oil recovery, the operating engineers can control the proper operating parameters of hydraulic fracturing. It can observe the maximum net present value at which the operating parameters of hydraulic fracturing were determined.

The net present value model is to estimate the economic performance based on the field of drilling and production contractor offshore Vietnam. A simple cash flow model in an Excel spreadsheet calculated from the yearly income includes the depreciation regarding a typical contractor fiscal regime in Vietnam. These simulator cases run over 10 years of each case, and the results include the cumulative oil

production of the fractured well, injection time, leak-off coefficient of hydraulic fracturing, the amount of proppant used, the amount of the used fracturing fluid of the each run has been gathered. Thus, these input parameters for the net present value model consist of the average oil price of 60 $/bbl, fracturing fluid price per gallon of 1 $/gallon, proppant price of 1 $/lb, hydraulic horse power price of 40 $/hhp, fixed price of 30,000 $ and the discount rate of 10% of the Contractor Field Vietnam (2015). In the pressure model, the surface treating pressure is set up to 6,000 psi which is very important parameter in order to estimate the pump horse power requirement.

RESULTS AND ANALYSIS

Response surface method is more convenient compare to traditional single parameter in order to find optimization of the response value. In this research, there are a total of 27 run cases to find where the point of these variables optimized each parameter in the current design of experiment. Table 5 has shown the result of the experimental conditions

and the response of the net present value of each run case, and the amount of oil recovery of each run case in 10 years of oil production scenario according to the central composite design. In table 5, it is easy to observe where the point has been maximized. This is the maximum net present value at run case of 12 under operating parameters of hydraulic fracturing of 22 bpm of injection rate, 120 minutes of injection time, and 0.003 ft/min$^{0.5}$ of leak-off coefficient. Especially on the run 12, the maximum oil recovery where reservoir porosity reaches 18%. By the response surface, the relationship between these variables and the response of the net present value has been correlated as:

$$NPV = 12.8025 + 0.15 X_1 + 0.216667 X_2 - 0.55 X_3 + 0.98 X_4 - 0.0537043 X_1^2$$

$$- 0.0537028 X_2^2 + 0.0190021 X_3^2 + 0.103704 X_4^2 - 0.025 X_1 X_2 + 0.0375007 X_1 X_3 \qquad (20)$$

$$+ 0.0125 X_1 X_4 + 0.075 X_2 X_3 + 0.025 X_2 X_4 - 0.0625 X_3 X_4$$

Accordingly, the results of the analysis of these variances in table 2 have shown the ANOVA of the quadratic regression model. From the ANOVA table, the determination coefficient of $R^2 = 0.99$ indicated that only a few percent of the total variations were not explained by the net present value model (20). Meanwhile, the value of the adjusted determination coefficient (Adjusted coefficient $R^2 = 0.98$) according to the net present value model (20) was highly significant.

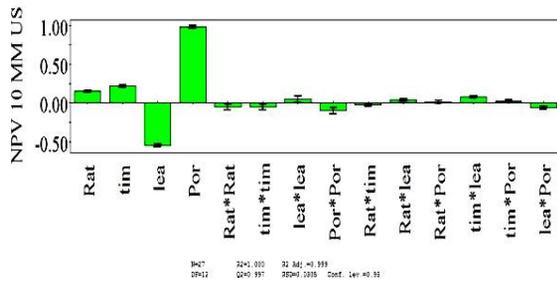## MAIN EFFECT PLOTS ON THE NET PRESENT VALUE

Fig. 2. The effects of these variables on the net present value (NPV)

The main effect plot is appropriate in order to analyze data based on the design of experiments. The expected main parameters affect the net present value of the response. Fig. 1 has shown the effect plot of the variables on the net present value. Accordingly, the figure has been divided into two regions. The first region presents these variables of the negative factors such as X_3, $X_1.X_1$, $X_2.X_2$, $X_4.X_4$, $X_1.X_2$, $X_3.X_4$ that decrease the net present value. Especially, one of the big variable effects on the net present value is the negative factor of leak-off coefficient. This explains why during hydraulic fracturing, more leak-off coefficient as well as larger volume loss into the reservoir leads to shorter fracture half-length. Therefore, the result of fractures is low fracture conductivity as low oil recovery. In the second region, these factors are above zero, which present positive value such as reservoir porosity, X_4, injection time, X_2, injection rate, X_1, injection time × leak-off coefficient, $X_2.X_3$, injection rate × reservoir porosity, $X_1.X_4$, injection time × leak-off coefficient, $X_2.X_3$, injection time × reservoir porosity, $X_2.X_4$. Accordingly, the higher reservoir porosity of course leads to high net present value due to more reservoir porosity of high oil recovery. Fig. 2 presents the actual net present value and predicts net present value versus data number. The predicted data approximates the actual data. Thus, the model is highly significant. Through fig. 2, the reservoir porosity much affects the net present value. Accordingly, the high leak-off coefficient decreases the net present value because the leak-off coefficient is inversely proportional to the fracture half-length. This is because the high leak-off coefficient during hydraulic fracturing makes more fluid volume loss into the fracture face area among the fractures, which leads to reduce in the fracture volume, shorter fracture half-length and low fracture conductivity. The results are low oil recovery of low net present

value. Fig. 3 presents the actual net present value and predicts value versus the data number. Through the model it is highly significant with the coefficient confident factor of R-square reaching 99%. The fig. 4, 5, 6, 7 present the single parameters as injection rate, injection time, leak-off coefficient, and reservoir porosity that effect the net present value. Especially in fig. 6, the increased leak-off coefficient leads the rapid increase in the net present, compared to other figures.
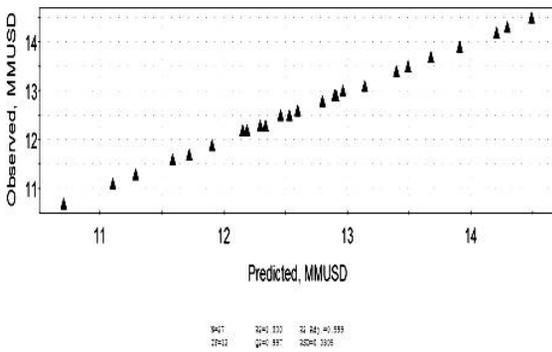

Fig. 3. The actual net present value (NPV) and predicted net present value (NPV) versus data number
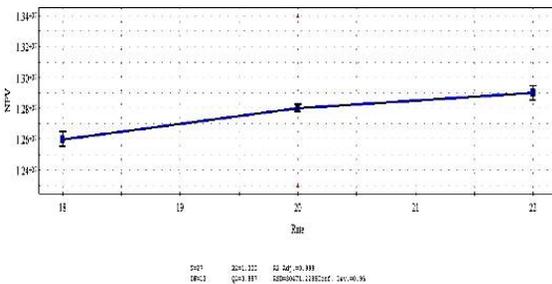
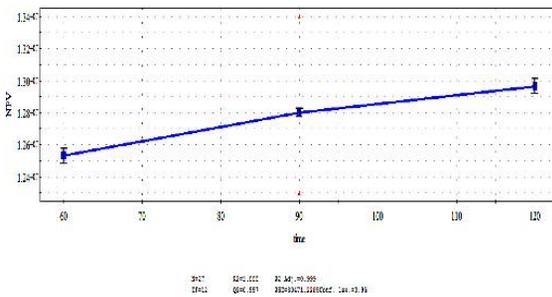*Fig. 4.* The effect of the injection rate on NPV
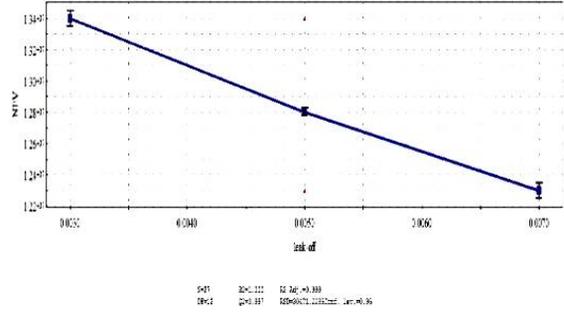

Fig. 5. The effect of the injection time on NPV

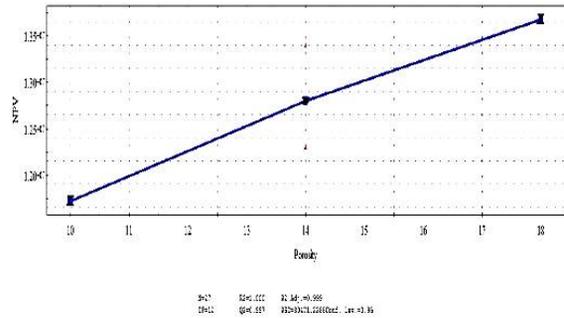*Fig. 6.* The effect of leak-off coefficient on NPV

Fig. 7. The effect of reservoir porosity on NPV

CONCLUSIONS

Through this work there are a total number of 27 run cases by using the central composite design (CCD) which is designed for 4 variables such as injection rate, injection time, leak-off coefficient and reservoir porosity in this field with the response of the net present value for production recovery of 10 years. On the other hand, the 2D PKN-C model is combined with the unified fracture design based on the given proppant mass of each run case. The author could summarize the main points as follows:

The main single parameter as leak-off coefficient much affects the decrease in the net present value in the post hydraulic fractured well in 10 years.

The main single operating parameters such as injection rate, injection time, and reservoir porosity are directly proportional to the net present value.

The reservoir porosity strongly affects on the net present value compared to the other variables.

The main effect plots and interaction effect plots presente the effects on the net present value.

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